PUBLIC VERSION

Preliminary Investigation Of the Idaho PCA Framework With Regard To Idaho Power Company and Idacorp Energy Services Trading and Risk Management Services

Conducted For:

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This document was prepared for the Idaho Public Utility Commission in the Matter of the Application of Idaho Power Company For A Refundable Emergency Energy Charge For The Recovery of Extraordinary Power Expenses covered in Case Number IPC-E-01-07. This is a Final Report that incorporates verbal comments received from IPUC participants. Its primary purpose is to explain our findings, address outstanding questions and stimulate discussion. We offer detailed recommendations regarding these topics. Comments and suggestions should be directed to the Project Manager Patrick Beathard on 512.261.3663 (pbeathard@teknecon.com).

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Introduction

The Idaho Public Utility Commission Staff retained Teknecon Energy Risk Advisors, LLC to provide expertise about trading and risk management to the Commission Staff. The focus of these activities was to provide insight in two proceedings.

The first is the Matter of the Application of Idaho Power Company For A Refundable Emergency Energy Charge For The Recovery of Extraordinary Power Expenses covered in Case Number IPC-E-01-07. The second is the Matter of the Application by Idaho Power Company for Authority To Implement An Early Power Cost Adjustment Rate for Electric Service To Customers In The State of Idaho For The Period of May 1, 2001 through May 15, 2002 covered in Case Number IPC-E-01-11.

There are three major areas of concern:

I. Examine the past and existing Idaho PCA frameworks to see where we have been.
II. Provide Observations About the Current Status of Activities of Idacorp Energy Services (IES) on Behalf of Idaho Power Company (IPC) To Give Insight As To How the Goals and Expectations For the Idaho PCA Framework Have Been Met.
III. Provide observations, recommendations, and suggestions about how the proposed services agreement between Idaho Power Company (IPC) and Idacorp Energy Services (IES) might be modified to provide additional protections to customers of Idaho Power Company (IPC) served under regulated tariffs; and provide insight and observations about how the existing Idaho PCA framework might be modified.

Review Process

During the course of the engagement, a review was made of documents in the Matter of the Application of Idaho Power Company For Approval of an Agreement For Electricity Supply and Management Services Between Idaho Power Company and Idacorp Energy Solutions L.P. covered in Case Number IPC-E-00-13. This review was performed on three documents; the Settlement Stipulation dated November 17, 2000; the Final Order 28596 (copy undated); and, a document entitled "Statement of Policy and Code of Conduct Governing the Relationship Between Idacorp Energy and Idaho Power Company" that is unsigned and undated and includes Appendices. References to Idacorp Energy Services (IES) are associated with trading and energy services that will become IES when all approvals are received and the activities are transferred to the unregulated subsidiary.

In addition, a brief review was made of the Commission Staff notes of IES transactions entered into in December, 2000; January, 2001, and February, 2002. Discussions were held with Commission Staff to better understand prior audit information, and anomalies already identified. Commission Staff made additional requests for information to IES/IPC under Staff's audit authority; however, some of the responses to these questions were not received in time for inclusion into this report.

In addition, we reviewed a document entitled "Idacorp Energy Trading & Financial Risk Management Policy". This document contains risk management objectives, possible tools to be used, a summary of policy, processes, and procedures, the roles of various departments in the trading and risk management process, an outline of the controls on trading, and an outline of the risk measurement process.

Also, we reviewed a document entitled "Idaho Power Company Response To First Production Request of Commission Staff" in Case Number IPC-E-01-07. This document was largely focused on reserve margins, the integrated resource plan process, projected and historical energy surpluses and deficiencies, transmission planning issues related to transmission constraints, and reliance on market purchases.

In addition, we reviewed the available IES/IPC responses to several Commission Staff Audit requests.

A discussion of deal capture processes and access to deal information was held with Commission Staff.

Finally, a discussion of the proposed framework for transactions between IPC and IES was held with Commission Staff.

Limits To The Review

This evaluation and report development was undertaken over an eleven-day period.

In such a short time period, it is unlikely that the most comprehensive and thorough investigation was undertaken. Due to the imposed time constraints, the review of IPUC notes regarding the transactions undertaken for system purchases and sales were focused only on the months of December, 2000 and January, 2001.

In addition, Dow Jones Mid Columbia index data were purchased for the study examination period. A comparison of these prices with prices contained in Staff notes was undertaken and anomalies were noted. However, a comprehensive analysis could not be undertaken during the allowed time to explain these anomalies. At least part of these are due to the combination of heavy load hours (HLH) and light load hours (LLH) plus transmission costs. However, a tie back to the original index data in the time allowed was not possible.

Commission Staff raised other information and points in discussions. Many points were accepted as fact but not verified by TERA due to time constraints. For example, we did not review source documents relating to Risk Management Committee decisions. In at least one case, a specific action was identified by Commission Staff that appears inconsistent between the Idacorp Energy Trading and Financial Risk Management Policy guidelines and subsequent activities undertaken by IES.

I. A. Examine the Past and Existing Idaho PCA Frameworks To See Where We Have Been - Philosophy Of The PCA Clause

From a philosophical perspective, we adopt the notion from the finance world that rational investors and market participants trade off risk and return in an almost continuous fashion. This entails certain assumptions about decision-making and information flow; however, it is a powerful argument.

It is not clear to us from the facts presented to us what precisely the nature of the relationship is between IES and IPC, both at the current time, and as contemplated under the "Statement of Policy and Code of Conduct Governing The Relationship…". In addition, the rationale used to develop the existing framework is not well documented. As a result, we begin this discussion by reviewing the background of the PCA clause and the incentives for managing these costs directly.

In the past, it is likely that customers paid the cost of power procurement. In other words, if IPC took risks on their behalf to procure lower cost power, the customers paid the amount due whether IPC efforts reduced or increased these costs. Typically, under this construct, the managing company (IES and IPC in this case) did their best to reduce cost and risk in a prudent and reasonable manner, but in essence they were not highly incentivized to take management risk on behalf of the captive consumers to reduce cost or bill volatility since there was not an explicit reward for this behavior. Nevertheless, some transactions were risk and/or volatility reducing since this was the generally "prudent" behavior. This can generally be thought of and referred to as "the lower of cost or market" approach in a risk regime that is appropriate for captive consumers.

Under a typical "lower of cost or market" approach for prudent and reasonable expenses, system units owned by the company would normally be operated and dispatched if the cost of running them was below alternatives available from the market. If market alternatives were less expensive, purchases would be made to take advantage of these lower costs for the captive consumers. This rule was general; there was no distinction between short, medium, and long-term deals.

The managing company was expected to make prudent and reasonable decisions to operate the system's assets in a manner that delivered the "lower of cost or market". Generally, risk increasing or speculative transactions, were discouraged; however, the risks were usually poorly or never calculated since the science of risk measurement was not well advanced at the time. In addition, company business processes were not organized trading and risk management; consequently, considerable discretion was left to management to accept risk and reduce costs. However, just as any reasonable person would "shop around" to lower costs, staff and management commonly worked to lower wholesale costs since this was "prudent". Additionally, the system was designed to deliver these benefits directly to the captive consumer in a manner that did not disadvantage the managing company financially. This meant that the cost recovery process was streamlined and standardized, recognizing that the company had little incentive to interfere with the reasonableness of these costs.

Under existing PCA treatment in Idaho, our view is that the clause is no longer consistent with this "lower of cost or market" philosophy.

To understand why this is so, it is important to review the PCA clause mechanisms as it applies in this case. Our understanding is that prudent and reasonable costs and revenues related to hourly transactions will be charged to IPC at cost into the IPC system. Note also that no ready market price exists for these transactions. With regard to day-ahead transactions (or balance-of-month transactions throughout the current month), costs will be transferred from IES to IPC at index (usually the Dow Jones Mid-Columbia Index and possibly at the Dow Jones Palo Verde Index) regardless of the cost of the power to IES. The difference between cost to IES and the index transfer price is the profit or loss that accrues to IES. These transactions are referred to as "Intramonth Power Marketing". With regard to forward or term transactions (typically beginning in the next calendar month and extending into the future), costs that are prudent and reasonable are to be transferred from IES to IPC.

Although the philosophy behind this structure has not been comprehensively articulated, it appears to us that the objective of this clause is to provide an incentive to IES and IPC to keep costs no higher than market. Perhaps the thinking behind its formation was that by allowing the opportunity for a profit to IES for a class of transactions and capping the cost to IPC's captive consumers at market, the trading and risk management talent that would be made available to IES using such a guarantee could also be employed to keep costs low for the other two classes of transactions where IES would not earn a return.

Under the general "lower of cost or market" philosophy for prudent and reasonable costs, it seems likely to us that IPC continues to have the responsibility to operate under this philosophy for the real-time and term transactions. For intra-month transactions, IPC is guaranteed to buy at market, giving up the opportunity to buy below market and the risk of buying above.

How has this hybrid philosophy worked in practice? We devote considerable discussion to the related details in later sections of this report. However, a few general observations are useful at the outset.

It is our observation that with regard to term transactions, IES and IPC appear to believe that if the IPC system is expected to be physically short or long in the future, "hedging" transactions can be undertaken to balance the system. For example, if the system is forecast to be short of capacity in a future quarter, but long in a second quarter, it is acceptable to sell the expected surplus while simultaneously purchasing the expected shortfall. If this is indeed IPC's philosophy, we agree that this is desirable behavior. We are reasonably confident that over time IPC can demonstrate some savings to the captive consumer given an appropriate implementation of this philosophy.

However, to us, “hedging” requires both a view of volumetric variance *and* future prices across a variety of time-frames. If IPC makes a long-term decision in advance based on a price relationship between future prices, it is clear that captive consumers will be best served if the transaction is risk-reducing.

We would agree that matching surplus and deficit is likely to be risk reducing. However, we would argue that the captive consumer is also interested in the total cost, the volatility associated with the potential charges in his bill under the PCA, and the “value at risk” or VaR of these potential future transactions. Prices and forecasts of supply-demand balance typically change through time as more information becomes known and expectations change. As a result, to achieve a philosophy consistent with prudent and reasonable implementation of “lower of cost or market”, our view is that it is important to hedge and manage risk across *all* time frames.

Throughout our review, we were struck by the notion that IPC and IES seem to be primarily focused on physical shortage or surplus for the captive consumer as a trigger for risk reduction. We believe that the dollar impact on captive consumers is also important, and can be an equally, if not more important trigger for risk reduction. We also believe that captive consumers are well served by reducing the volatility of future bills from a total dollar perspective.

From our perspective, the existing PCA framework does not clearly reinforce this idea. It seems to proceed under the concept that term hedging based on price is not appropriate for IPC. Hedging is only appropriate to balance supply and shortage to meet operational needs against forecasts that change over time. So under this philosophy, IPC and its captive consumers should expect to have a balanced supply book. For these transactions, IES and IPC seem to be saying that the consumer should expect to pay a price based primarily on the cost of generation.

However, as the timeframe becomes shorter, say over a one-month period in the future, the PCA framework changes from the prudent and reasonably incurred “lower of cost or market” viewpoint. Under the current structure, the net effect is that the captive consumer is being told that you do not need to hedge and manage risk across the intra-month time frame. You can expect no better than “market”. So, it is possible that certain risk reducing transactions exist across this shorter timeframe, but the captive consumer cannot benefit from these under the current structure. In addition, there may be low-risk transactions that are available across this timeframe, but the captive consumer has lost the opportunity to be exposed to them. And, if one were to compare the nature of a one-month transaction to a one-day transaction, the size of the risk to the captive consumer is very likely to be greater for the one-month transaction under normal price environments. From a social choice perspective, if a risk-adverse captive consumer desired to take risk, it is clear that the place to do so would be in the intra-month and real-time time frame. However, under the current framework, he is precluded from doing so. (It should be noted that the view of IES in this matter might have the appearance of being tainted by its existing opportunity to earn a return in this time period.)

For the real-time transactions, the existing PCA framework changes back to a philosophy of prudent and reasonably incurred "lower of cost or market" charges. In this category, since there is not an organized real-time market or power exchange serving Idaho, it is also important to note that a continuous market price is more difficult to determine.

I. B. Examine the Past and Existing Idaho PCA Frameworks To See Where We Have Been - Philosophy Regarding The Relationship Between IPC and A Portfolio Manager

Under the existing PCA clause and regulatory structure in Idaho, IPC customers may desire to act on their own behalf to balance risk and return in making power purchases, but they are often precluded from doing so. A possible exception exists for some industrial tariffs or buy-through agreements that have not been reviewed. However, it is our expectation that end-use customers are typically not able to engage in these types of decisions when markets are not contestable and they are supplied under tariff. Under the historical regime, IPC made these decisions for them.

In the future, our perspective is that this type of decision-making will need to continue if the principle of prudent and reasonably incurred "lower of cost or market" is to be retained. This means that those acting on behalf of captive consumers (regardless if it is IPC or an agent of IPC, such as IES) need to act with consumer interests and wishes in mind as a primary focus. The Existing Framework for the IES-IPC relationship is silent on this point; however, we believe that this view does apply and extends from the regulation of IPC by the IPUC.

What are the characteristics that indicate that someone is acting effectively on behalf of the captive consumer? First, the captive consumer has the right to expect fair and honest dealing from IPC and any portfolio manager (e.g. IES) acting on its behalf as agent in obtaining assistance for things like energy supply, management, marketing, and brokering services. However, if the relationship is specified as a totally arms-length one, then the philosophy of "buyer-beware" is in effect, and IPC needs to provide its own independent oversight as a check on what it is receiving. In our mind, the proposed Policy is silent on this point.

If a portfolio manager is acting as agent, it is our opinion that the financial markets typically reward this activity through a fixed fee plus an incentive fee. The incentive fee can be of many types including transaction based, percentage based on performance compared to a benchmark, or lump-sum goal-based. In our experience, an incentive fee of some type is normal, customary, and necessary to attract qualified talent and retain it.

It is also customary for the customer to expect that transactions are offered to him (through his portfolio manager) first, and that the offer is bona fide. Put another way, this means that the customer should not be subjected to "front-running" where another party (the portfolio manager or a third party) is offered the transaction first and then "flips it" or sells it to the customer after an intermediate holding period.

Put another way, the customer normally expects that the price the portfolio manager is paying is fair and not subject to manipulation. In addition, the customer normally expects that the portfolio manager does not possess enough discretion to "adjust" or "bend" the rules of the relationship to his benefit.

If a relationship is arms length, it is our opinion that the financial markets typically reward this activity through a "what the market will bear" concept. This means that sales transactions are undertaken at the lowest price the identified seller will accept and purchases are made at the highest price the identified buyer will pay. Under these arrangements, there should be no hidden support by utilizing assets of the other party without express agreement and compensation.

II. Provide Observations About the Current Status of Activities of Idacorp Energy Services (IES) on Behalf of Idaho Power Company (IPC) To Give Insight As To How the Goals and Expectations For the Idaho PCA Framework Have Been Met.

In the previous section, we outlined the notion that a reasonable PCA framework is based on the concept of prudent and reasonably incurred "lower of cost or market". We also offered observations about the current status of the PCA as it applies to IPC, and noted that three categories of transactions were contained in the PCA. Further, we made the observation that two categories of prudent and reasonable expenses (long term hedges and real-time trading) were passed through the PCA clause at the "lower of cost or market". A third category of prudent and reasonably incurred expenses associated with intra-month power marketing was passed through the clause at a guaranteed market price.

We also introduced the idea that the nature of the relationship between the parties is determined partly by the responsibilities that each assumes, and partly by the actual arrangements that are made to transact business. In the case of IES and IPC, two of these arrangements that will need to be examined to determine the nature of the relationship between the parties include credit support and the contractual marketing/trading arrangements with counter-parties. In addition, the risk management objectives, process, controls, and measurements help determine and verify the nature of the relationship.

If the nature of the relationship can be established, and the goals of the PCA clause are agreed upon, it then becomes important to ensure that the actual structure of the fixed fee and incentive structure between the portfolio manager and IPC reinforce the desired behavior, and avoid even the appearance of conflict of interest. This can require certain information to be reported for outside audit, and it can sometimes require tabulation of additional or new information.

To better understand the comprehensive nature of the relationship between IES and IPC, and the relationship to the PCA clause, we developed a list of questions and attempted to answer these individually. Taken collectively, we believe the answers to these questions summarize the nature of the relationship and provide guidance as to the types of concerns that should be addressed for improving the current PCA mechanism.

1. What is the nature of the contract between IES and IPC? Is it in place yet?

   We have reviewed a copy of the "Statement of Policy and Code of Conduct Governing the Relationship Between Idacorp Energy and Idaho Power Company" (hereafter, the "Statement"). This document is designed to cover the activities of IES as it interacts with IPC. We are informed by Commission Staff that this document is not signed, and therefore not in force.

2. Has IES registered with FERC and obtained a Power Marketer certification?

   We reviewed the FERC website to evaluate the status of IES and IPC. We also reviewed the FERC website to determine if IPC had the authority to sell at market-based rates.

   Beginning in 1997, IPC was listed as a registered power marketer by FERC. The listing was last updated on 6/4/1998. As of March 27, 1997 IPC had received Commission approval of market-based rates. Also, IES did not appear on FERC's Affiliated Power Marketer list, nor on FERC's Affiliated Power Producer list. We are informed by Commission Staff that they do not believe that IES has received its Power Marketer certification from FERC.

   If Issue 1 (above) had resulted in a signed contract, it would appear that IES would not be in compliance with Section 2.C.8 of the Statement which reads that "IES shall observe all applicable laws, ordinances, rules, and regulations relating to delivery of the Services, and shall procure and maintain in force, at its sole expense, all registrations, permits, licenses, and approvals required by law or governmental authority to perform the Services."

3. What is the nature of the pricing mechanism that is contemplated under the Statement?

   We have reviewed the document and summarize the pricing mechanisms as follows:

Deal Type	Term	Purchase Or Sale	Price/Cost Characterization
Real Time Power Marketing	Hour Ahead To 12 Hours Ahead	Both	Procured by IES at cost and transferred to IPC at the average of all real-time transaction prices entered into.
Intramonth Power	Day Ahead To Balance	Both	Procured by IES at cost and transferred to IPC at Index (Dow Jones Mid-

Marketing	Of Month		Columbia or Palo Verde) plus transmission costs selected by IES from established transactions/tariffs.
Hedging Management	Month Ahead and Longer	Both	Procured by IES at cost and transferred to IPC at cost.

4. Can you outline the nature of the transaction deal flow between IES and IPC?

   From the documents presented to us, the nature of the transaction flow between IES and IPC cannot be fully determined.

   To assist us in understanding this process, we posed the question to Commission Staff and received the following guidance. Staff's understanding is that IES only makes purchases "for" Idaho Power, when specifically directed by the Risk Management Committee. These transactions are primarily to address physical imbalances that might be present in the longer term ("hedging management" transactions), typically on a monthly, quarterly, or annual basis. In the normal course of operations, IES only makes purchases for themselves. IES then sells day-ahead or real-time power to IPC from their inventory. IES may recommend and/or make a deal long term or term for IPC with proper authorization. Staff believes that if they do this, they do it in IPC's name, not the IES name or non-operating book. If they make a long term or term deal for IPC, it is done with RMC approval or direction.

   Staff indicates that they understand that a deal on the IES purchases journal, which happens to be purchased from IPC, will show up as a sale on the IPC sales journal.

   Staff's understanding is that when IES is selling to IPC, they show it as a sale on the IES sales journal, and IPC shows it as a purchase. All purchases and sales from third parties (not IPC's operating book) are directly from the market, and they are all IES sales and purchases. Staff's understanding is that Intramonth Power Marketing Deals are then transferred from IES to IPC at the Dow Jones Mid-C index price. Real Time Power Marketing Transactions are then transferred at the real-time weighted average calculation for the period in question. We have not had the opportunity to review the supporting documentation for this calculation in detail.

   It is our understanding that Staff has reviewed a listing of sales by month between the IES and third parties, a listing of purchases by month between IES and third parties, a listing of sales by month to IES from IPC; and a listing of purchases by month by IPC from IES. Summaries of these data have been provided to us for review.

5. What is the fee that IES can expect from IPC? Why did IPC not include the fee in the filing?

   According to Paragraph 6.1 of Attachment 1 of the Statement, IPC shall pay to IES USD $300,696.30 per month, or $3,608,355.60 if the contract was continued for one year. (The term of the proposed agreement is not included in the documents we reviewed; it appears to be in effect until modified.)

   In Paragraph 3 of the Settlement Stipulation, the annual charges from IES to IPC under the Agreement shall not exceed $5,000,000. It is not clear to us if this cap on charges applies to the fixed fee, or to the total compensation (fee plus incentive) that IES can expect to receive.

   According to the Settlement Stipulation documents reviewed, it appears that IPC will pay to its customers the sum of $2,000,000 in a rate reduction. It is not clear to us if these two amounts are somehow related.

   We cannot be sure that IPC did not include the fee in the filing made with the Commission or why. If they did not include it, one reason may be that the contract between IES and IPC is not in place.

6. Did IES/IPC utilize the preexisting prudent and reasonably incurred "lower of cost or market" rule or the prudent and reasonably incurred "market price transfer" rule outlined for the Intramonth Power Marketing amounts in its filings?

   Commission Staff indicates that IES and IPC did not utilize the "lower of cost or market" approach for Intramonth Power Marketing in the most recent filing. They believe that IES and IPC did utilize the "market price transfer" approach.

   Based on our review of Commission Staff documents and notes, it does appear that the IES/IPC Intramonth Power Marketing transactions were priced using the "market price transfer" approach. These transactions appear to have been undertaken utilizing the Dow Jones Mid-Columbia Index. However, it is not possible for us to verify this based on the information on-hand and that presented by IPC/IES. This is because we do not have separate prices for transmission, nor do we have the HLH and LLH energy totals that would be used to volume weight the calculation. In addition, there is little guidance in the Statement or other documents to justify how a transmission price is decided upon and entered into the system.

   There is a separate issue related to if the market price transfer included charges that were prudently and reasonably incurred. We suggest that we would need more detailed pricing and deal information from both IES and IPC including a better understanding of the business processes and practices in place during that time to make this determination.

In addition, we would suggest additional discussions would be necessary to determine what type of transactions were to be allowed between the three product classes and the two parties based on the initial intentions and goals of the program, the selected strategies, and their implementation under the PCA clause.

7. If IES is not a registered power marketer, how can they enter into an agreement with IPC or on behalf of IPC?

   This is a legal question for which we cannot offer an opinion.

   However, Commission Staff indicates that they are advised that IES may have acted in the name of IPC to execute these transactions. This means that IPC credit, documentation, and contractual arrangements may have been utilized.

   With regard to forward transactions, it is common for counter-parties to insist on documentation of who is authorized to trade. For example, if IPC was to enter into a forward transaction with Morgan Stanley, Morgan would likely require IPC to identify who is authorized to trade for them. This is often summarized in a document referred to as a Certificate of Incumbency, and is a feature of well-run trading and risk management programs.

   Following this logic, if IES was authorized to transact in forward markets for IPC, more sophisticated counter-parties may have required IES to provide a copy of its agreement with IPC and those authorized to trade on behalf of IES. If they could not produce these, one way they could transact forward would be as IPC employees. Another way to transact forward would be to have IPC indicate to all its counter-parties that IES was trading on its behalf. Typically, this type of notice is sent to all counter-parties. These notifications were not included as part of the transmittals sent to us.

   Based on the prevailing business practices of better trading and risk management operations, without the ability to produce these documents, it seems unlikely to us that IES could have entered into long term transactions for its own account.

8. Suppose hypothetically, that IES was trading on behalf of IPC (with IPC's credit and using IPC's agreements). In this event, should they receive the market price mechanism for Intramonth Power Marketing Transactions?

   This is a legal question for which we cannot offer an opinion.

   In a business sense, if IPC received the market price mechanism treatment previously when they undertook similar trading and risk management activities, IES and IPC would seem to us to be entitled to similar treatment unless the business activities undertaken by IES (e.g. business process, risks assumed, and expected return) were substantially different from those of IPC. We think the standards to be utilized here would be ones of prudence and reasonableness.

It should be noted that based on our business knowledge of markets and trading, it would be unusual to compensate an agent under a new compensation arrangement for activities undertaken prior to documentation being put in place. At best, when changes in staff or responsibilities occur, typically counter-parties limit transaction volumes until the documentation is sorted out. This often results in reduced compensation for the agent in the interim.

These new agreements and arrangements can often take months to put into place. ISDA documentation can routinely require 3-12 months to put in place. WSPP agreements can also require several months to process. Other documentation can also be utilized. We checked the WSPP website to determine if IPC is a signatory to the WSPP agreement. They are a signatory on Sheet 92.

Currently, it is not clear to us how IES would transact – as a member of WSPP or otherwise, or indeed which other contractual agreements they would transact term deals under.

9. FERC guidelines are specified in the Statement to with regard to transaction reporting guidelines. Are FERC reporting guidelines detailed enough to enable audit of a position and transactions between affiliated entities?

   Based on our business knowledge of markets and trading, FERC guidelines are substantially deficient in providing the necessary information to identify deal-flow, position, estimate price risk or VaR, or trace the history of transactions.

10. What types of documents and information are necessary to fully trace transaction flow and reach comprehensive conclusions about the deals between IES and IPC?

    In Section 2 of the Settlement Stipulation, IPC makes a commitment to facilitate audits. In Section 2.2, only the transactions between IES and IPC are allowed for review through internal and external auditor work-papers, and through Board and Audit Committee minutes.

    Based on our business knowledge of markets and trading, we do not believe that Commission Staff or anyone reasonably knowledgeable in trading and risk management can fully trace transaction flow and reach comprehensive conclusions about the deals between IES and IPC under the current arrangement. Our view is that access to complete transaction level detail of all parameters contained in IPC/IES position tracking system for all IES and IPC transactions would be the most straightforward and simplest way to understand the true nature of the costs and relationship between the parties. We believe this can be done on historical transactions only to protect the nature of the competitive concerns IES and IPC may have.

Based on conversations with Commission Staff, and our review of the materials provided, some of these materials were requested from IPC, and staff was not provided with what we would think of as information about "all" purchases and sales for a given month for both IES and IPC at the transaction and deal entry level. In our reading of the Stipulation, this may fall under the need for an "in camera" review. However, in order to address some of the issues outlined in Point 10 below, such data from the company in electronic format would be necessary in our view. Depending upon the nature and volume of data and questions at hand, our view would be that position tracking system access, including access to possible Value-at-Risk (VaR), Credit Value at Risk (CVaR), option, and other models would be necessary. Output from these models and possible reporting systems would be useful over many time periods, and these models may need to be operated interactively and prospectively if IES and IPC use any sort of scenario-planning approach for either volume or price assessment.

It is important to note that the importance of this issue to the participants depends on the guidance of the Commission with regard to what is a reasonable and prudently entered transaction. On the surface, from the documents we have reviewed, allowable transactions between the two parties do not appear to be limited beyond the three classes and transfer prices identified and summarized. Presumably, this was discussed between the parties and agreed to as reasonable. However, we are not familiar with past practices, or what additional representations were made to the Commission regarding the relationship between IES and IPC.

11. How could this lack of transparency become an issue?

This is difficult to fully address without a clearer understanding of the internal business processes of IES and IPC. However, for clarity, we will outline some transactions that, based on our business knowledge of markets and trading, have occurred in other settings.

At the outset, it should be stated clearly that we have no direct knowledge that any of these transactions have occurred in the IES/IPC case. Based on our business knowledge of markets and trading, we are providing this list of a few examples to stimulate discussion and illustrate the nature of the conflicts that can occur.

Front-running – Assume that a Counter-Party Z offers Marketer X a term deal of one month duration beginning next month for \$100/MWh. It is possible that Marketer X could purchase this deal for his spec book and resell it five days later as agent to Consumer Y for \$110/MWh. We would view this as undesired behavior because Marketer X may have had strong reason to believe he could sell the output to Consumer Y, and may not have entered the transaction without that arrangement. In addition, he has an implied option to hold a winning trade for further gain, or place a losing trade to Consumer Y. This can be an even bigger problem if Marketer X controls the volumetric needs forecast of Consumer Y.

Rule arbitrage – Let us describe how the transactions might be handled if there was no "rule arbitrage" and if there was "rule arbitrage". We will try to differentiate what might be viewed as desired and undesired behavior

Assume that Counter-Party Z offers Marketer X a term deal of one month duration beginning next month for $100/MWh in a market where this product is selling routinely for $150/MWh. Assume Marketer X believes that daily index prices will be about $150/MWh in line with current market expectations. If Marketer X places this on his spec book, he then has at least two embedded options. First, if forward prices rise after the purchase but before the start of the delivery month, he can resell the obligation to Consumer Y for a profit (since he didn't buy the forward for Consumer Y in the first place). We would view this as undesired behavior, since the below market forward might have been offered to Consumer Y, but was not. So, if Marketer X thinks spot daily index prices will be even higher, he can simply hold the forward obligation on his spec book if he knows Consumer Y is likely to need the power.

With access to a reliable forecast of consumption, he can make this determination, and increase his odds of a profitable trade since he can be reasonably sure that he has a customer for the daily power priced at market.

This might be referred to as an "implied put". Otherwise, he might be able to sell it above or below "market". This difference in price (above or below market) might typically be referred to as the "bid-asked spread". The bid-asked spread is usually relatively small in "liquid" markets where many simultaneous transactions with multiple counter-parties can occur. Usually, offers to sell are made at the "asked" price, while indications to purchase are made at the "bid" price. A typical range might be five cents to fifty cents per MWh. Sometimes, when markets are not totally liquid, there may not be a ready buyer or seller. In this case, having an implied put can be a trading advantage since there is a higher probability of having a transaction completed than would otherwise exist. This may or may not be desirable.

During times of system surplus, an implied call exists that allows power to be resold to Counter-Party Z. For example, Marketer X can purchase power forward for a month from Consumer Y when a forecast gives him confidence that Consumer Y will not need previously available power. If the daily Index Price is above Marketer X's cost, he can then resell it in the daily market at Index to Counter-Party Z for a profit with reasonable confidence that the power will be available all month. This may or may not be desirable. However, it is also important to note that Marketer X may not always be so altruistic. For example, assume that power is sold forward thirty days before the month of delivery from Consumer Y to Marketer X because Marketer X believes day ahead prices for the delivery month will be higher than the current forward price and Consumer Y is expected to be in surplus. Time passes.

Four days before the beginning of the month, Marketer X now believes that it is much less likely that the Daily Index price will be higher than his forward purchase price from Consumer Y, but the forward price for the month is still above the cost of the forward he purchased from Consumer Y. If Marketer X forecasts the volumetric needs of Consumer Y, and is responsible for setting the model assumptions, he could be tempted to modify these in line with his own financial position so that Consumer Y might now be showing a deficit for the month. In this case, he could resell the forward to Consumer Y, through his implied put, pocketing a profit that was generated at least partially by model uncertainty.

Firming Up Non-Firm Purchases – Assume that Marketer X has the right to purchase hourly or day ahead from Consumer Y. This constitutes an "implied call" on system resources. Marketer X purchases supply non-firm from Counter-Party Z and sells the supply firm to Counter-Party A. If the supply from Z is interrupted, Marketer X can easily buy from Consumer Y whenever he is in surplus (many hours) to continue to perform on his firm obligation to Counter-Party A. Marketer X compensates Consumer Y at cost.

This may or may not be desirable. We believe it likely that the compensation paid to Consumer Y is below the value of the service that is being provided unless Y receives an option premium payment for having the units ready to meet Marketer X's needs. This is typically compensation above the cost of production.

Counter-party credit defaults – Assume that an agent is operating for an asset owner and that the agent trades for his own account as well. Also, assume that these transactions are carried out with the same counter-parties. If counter-party credit defaults are "pro-rated" in a way that leaves discretion to one party, there can be the possibility of assigning credit defaults first to transactions held by the asset owner and secondarily to those held by the agent for his account.

12. Is allocation of credit defaults a realistic possibility in the case of IES/IPC?

We have not had the time or ability to review any materials to indicate that they have occurred. At this time, we cannot ascertain if a reasonable probability exists. We have noted from a recent 8K filing from Idacorp that the firm plans to net its exposure to CalPX based on an SCE and PG&E default. We quote:

"With regard to non-utility energy trading in the state of California, IPC in January 1999 entered into a Participation Agreement with the California Power Exchange (CalPX), a California non-profit public benefit corporation. The CalPX operates a wholesale electricity market in California by acting as a clearinghouse through which electricity is bought and sold. Pursuant to the Participation Agreement, IPC could sell power to the CalPX under the terms and conditions of the CalPX Tariff.

On January 18, 2001, the CalPX sent IPC an invoice for $2.2 million - a "default share invoice" - as a result of an alleged Southern California Edison (SCE) payment default of $214.5 million for power purchases. IPC made this payment. On January 24, 2001, IPC terminated its Participation Agreement with the CalPX. On February 8, 2001, the CalPX sent a further default share invoice for $5.2 million, due February 20, 2001, as a result of alleged payment defaults by SCE and Pacific Gas and Electric Company (PG&E), and others. However, as of February 9, 2001 the CalPX owes IPC $4.2 million, for power sold to the CalPX prior to December 2000. IPC will be entitled to receive an additional $7.1 million from the CalPX as of March 6, 2001 for December 2000 deliveries to the CalPX. IPC did not pay the February 8 invoice.

The CalPX allocated the defaults of, among others, SCE and PG&E to the remaining participants based upon the level of trading activity of each participant during the preceding three-month period. IPC believes that the default invoices were not proper and that it owes no further amounts to the CalPX. IPC intends to pursue all available remedies in its efforts to collect amounts owed to it by the CalPX. In addition to the amounts due IPC from the CalPX, IPC is currently owed approximately $750,000 from the Cal ISO for sales in November and an additional $36.6 million will come due to IPC from the Cal ISO March 6, 2001 for sales in December.

On February 20, IPC filed a petition with (FERC) to intervene in a proceeding which requests the FERC to suspend the use of the CalPX charge back methodology and provides for further FERC oversight in the CalPX's implementation of its default mitigation procedures.

Also a preliminary injunction has been granted by a Federal Judge in the Federal District Court for the Central District of California enjoining the CalPX from declaring any CalPX participant in default under the terms of the CalPX Tariff. We are unable to predict the outcome of these situations. In California, IPC believes that it has credit exposure in the range of $30-$40 million. The Company continues to manage this exposure in accordance with the established credit policies."

So, given the Statement, hypothetically how would a credit loss like this be allocated precisely? Since it is not clear to us whether the Statement is in place or not, would such a loss go to IPC, or are some of the transactions of IES to be offset as well? In the immediate case, this may be of interest since the Intramonth Power Marketing portion of the agreement may be operational from an income standpoint. The question also goes to the nature of the relationship between the parties. Is this an "arm's length" or "agency" relationship?

Further, if IES sold this power to the CalPX at a very high price, made a profit on it by marking it to Mid-Columbia Index price for IPC's book, and the counter-party defaulted on a higher priced sale to the PX, does this automatically mean that the IPC charge is only based on the Mid-C price and IES is responsible for the difference? We cannot tell how this would be resolved from the documents presented.

Conversely, if IES had bought from the PX for its spec book, and then delivered it to IPC at a higher Mid-C index, is it clear what happens in the event of default? Is IES responsible for the default at the PX price and IPC at the Mid-C price? Does IES share part of its "profit" to offset IPC's loss? If not, did IPC realize who IES was buying from and did it agree?

13. Do you have any examples of transactions where it is clear that IES or IPC may have engaged in the transparency issues listed in Points 11 or 12?

We do *not* have any examples where it is clear that IES or IPC may have engaged in the example activities listed in Points 11 and 12. That was not the point of the discussion in those sections. Our purpose was to show the possibilities; and, simply put, the problem's *appearance*.

Additionally, there is a chain of activities that occurred from November 21, 2000 through January 30, 2001 which are worthy of expanded comment.

Commission Staff informs us that on November 21, 2000, the IES RMC met and was presented with analysis that showed that IPC would be short in January, 2001. Staff has reviewed the information that was presented and informs us that the RMC knew at that time that there would be a shortage.

According to Staff's review of the minutes of that meeting, the RMC recommended and then unanimously approved the purchase of 75 MW/h flat for the entire month of January, 2001 to be purchased at the best prices available. However, the power was not secured as approved. Staff informs us that at least two reasons have been presented for that.

As a result, Staff feels an opportunity to purchase power at a relatively inexpensive $143 per MWH on November 21, 2000 was lost.

Staff informs us that inter-company correspondence shows that IES and IPC through RMC representatives considered additional transactions on November 30, 2000 and December 1, 2000. In these exchanges, a transaction to sell 100MW/h flat for the entire first quarter of 2001 was to be executed in exchange for a purchase to be made across the entire third quarter of 2001. One of the possible effects of this transaction would have been to make IPC even shorter in January, 2001. It is not clear if this transaction was carried out.

Staff informs us that the RMC met several more times in December 2000, but the meetings were focused on collecting Non-Operating funds from companies in California and other issues. No substantive mention was ever made again about the system shortage in January 2001.

On December 20, 2000, a series of daily, non-firm transactions were entered into by IES with [*a Midwest Party X*]. Staff notes indicate that IES entered into a non-firm transaction with [*Party X*] of 400 MWh/day (Deal # 37658) for all heavy load hours (5x16) for the month of January at $85.00/MWh. This represents a delivery rate of 25 MW/h.

On December 27, IES entered a sale for firm energy to IPC of 720 MWh/day (Deal #38568) for heavy load hours (6x16) for the month of January at $500.00/MWh. This represents a delivery rate of 45 MW/h.

Again, it should be restated that not all information is available to us to allow reconstruction of the trade. However, we find it interesting to note that the total of #37658 plus #38568 is 70 MW/h. This is close to the same amount that was identified on November 21, 2000 as required for the IPC system (75 MW/h). If access to the entire IES book were available, these transactions could be tied more closely.

From the information presented, it is not clear how the price of $500.00/MWh was arrived at. The Dow-Jones Mid-C Index (Firm, On-Peak) during the month of January arithmetic average for all days was $278.28/MWh. Therefore, the $500.00/MWh price must have been a term transaction that came from the market. However, it is not clear from the notes we have reviewed how this price was determined. We checked the Bloomberg listing for January 1 Month Forwards as of December 28, 2000 and the price for that day was listed as $522.50, so the price may be reasonable.

How might we interpret the proposed first quarter sale of 2000 and exchange purchase for the third quarter of 2001? It probably was an honest effort to reduce the overall risk for the IPC book and its captive consumers. It may show overall benefits for the captive consumers.

However, potentially it also had the net effect of transferring system resources from IPC to IES at cost, and giving IES the opportunity to sell the power back to IPC if it needed it in January at a market based price on a daily basis. If IPC was indeed already short in January, it also increased the probability that IPC would need to purchase more power from the daily market, without knowing what the market price would be.

Let us set aside this transaction, and spend some more time in a different area.

How might we interpret the purchase from [*Party X*]? First of all, this appears as a series of daily deals entered into in advance at the same time (on December 20, 2000) for delivery in January, 2001. It is possible that this transaction is of several types, but since it is entered into with one transaction number and multiple entries one for each day, it seems quite reasonable to characterize it as a "strip of dailies" entered as a term deal. Second, according to Staff notes, the transaction was entered into as "non-firm".

Why would [*Party X*] enter into a strip of daily non-firm deals at a fixed price rather than a month-long transaction? Perhaps the transmission path was not reliable, or it was available only on a "surplus" basis.

For example, this might be the case if power were flowing across the DC intertie from the Eastern Interconnection to the Western Interconnection. This hypothesis has not been tested with actual data due to the lack of time and information.

In our hypothetical world, does this mean that IES had little use for the [*Party X*] non-firm power? A relatively common transaction in trading is to turn non-firm energy into firm energy by augmenting the reliability with system or outside resources. This means that for some reason the power is cut, a second supplier can step in to make good on the transaction. IES could do this by going to the market and paying the cost prevailing at the time to replace the power. Alternatively, it could be that the "implied call" from the IPC system itself could be used to firm up the transaction.

In our hypothetical world, did IES have reason to believe that the [*Party X*] power schedule might be cut during the month? Based on the notes we have reviewed, there is no way to know this. A review of the actual schedules and deliveries would prove useful here. However, we checked to see if any similar transactions were undertaken previously in attempt to determine how comfortable IES was with the performance of [*Party X*].

Interestingly, we find that a very similar transaction was entered into on November 20, 2000, one day before the RMC meeting, with [*Party X*] for $85/MWh which is the same price as the December, 2000 transaction. This November transaction may be listed as two transactions (or there may have been a transcription or data entry error), but the net effect is the same for the month of December, 2000. That is, a daily strip was purchased for all days in the same volume as was purchased for January, 2001 on December 20, 2000. It seems acceptable to observe that IES must have been "reasonably comfortable" with the performance of [*Party X*]; otherwise, they would not have entered into the second transaction in December, 2000.

There are some observations and some speculation that is useful here.

First, the transaction for December was entered into one day before the RMC meeting. At this time of the month, traders would likely have formed opinions as to the profitability of the $85/MWh deal. The arithmetic average for the Dow Jones Daily On-Peak, Firm Index for Mid-Columbia was $541.97/MWh in December (after the fact). According to staff, the forward price on November 21, 2000 for January was $143.00/MWh. While the forward price for December was almost certainly different, it might typically be of the same order for winter.

Secondly, by entering the transaction in this fashion, IES may have believed they were entitled (and they may indeed be entitled) to receive the market price since the deal was a forward strip of dailies. If they had entered into a forward transaction, they would have needed to transfer the transaction at cost (and received no incentive fee).

Third, if IES used the IPC system to "firm up" the transaction, it is unlikely (based on the information we reviewed) that IPC received an option premium for the "implied call" it provided to firm up the resource.

Fourth, if IPC resources were used to "firm up" the transaction, it is unlikely that IPC received the deal as a firm forward transaction priced at cost (which it is now equivalent to in many respects). If outside resources were used under a 30 day contract to firm up the resource, then IPC is paying a daily price for what is, in net effect, a monthly contract. Also, if IES decided to take the risk to firm up the transaction for its spec book, and go to the market to firm up the transaction only when needed, it utilized the credit and trading authority of IPC to firm this up (assuming the Statement legal status outlined previously is correct). And, with regard to using market transactions to firm up the [*Party X*] transaction, without transaction level detail on IES purchases, an outside party cannot trace if the purchase was used to replace the interruption, or it was sold to IPC because they were short that hour.

It should be emphasized that this scenario is purely hypothetical, and it is unlikely that the actual developments parallel the hypothesis. However, the point of the discussion is that the fact-set can lead to an *appearance* of impropriety from the perspective of consumers. By developing this scenario, we do *not* mean to say or imply that we have reason to believe that IES or IPC engaged in these activities. Rather, we are making the important point that a reasonable person cannot be certain what has been done.

From an appearance perspective, we believe this is an important point that Staff and the Commission may want to consider in this and potential future reviews. Some of the outcomes of these investigations could have a bearing on what is considered reasonable and prudent. In our section titled Alternatives, we present some different ways that these factors might be addressed.

14. If IPC went out and held an RFP process to qualify an external and independent power marketer to trade around their assets, wouldn't these same issues exist?

    Not necessarily, but it is not possible to know for certain.

    For example, let us consider the case of the potential credit default described earlier. In the case of an independent power marketer, the transaction might be structured so that all power would be sold through an arms length transaction. If this were the case, assume the following fact set. Now, if the totally independent marketer (IM) purchased power from IPC and resold it into the Cal-PX, the IM would be assuming the credit risk of default from IPC and the Cal-PX. So, if IPC performed, and the Cal-PX did not, the IM would be responsible for the loss from the Cal-PX, and would need to honor its obligations to IPC.

    If the nature of the relationship was not arms length, but as agent, then IPC should probably be responsible for the credit losses.

    However, now assume that the IM has additional purchases and sales in a separate book that cannot be reviewed by IPC. Can IPC be absolutely assured that the sales reported by the IM as made to the Cal-PX actually were made, and not simply reassigned or allocated after the fact? Without full review of all transactions, it becomes difficult to reach this conclusion absolutely.

15. Are any problems with the market index methodology noted?

    There are three main questions that we were not able to resolve during our review primarily due to time and information constraints.

    First, are different deals accounted for and priced correctly from a quality perspective (on peak versus off peak, firm versus non-firm, round the clock)? Traders refer to these price differences as "quality basis". For example, Dow Jones usually reports firm and non-firm indices for heavy load hours (HLH) and light load hours (LLH). Is the appropriate index being used to mark each trade? When a 24-hour deal is done, is the appropriate price being applied to the appropriate volume? In addition, if deals are done for all hours except four super-peak hours and augmented with four hourly purchases at cost, should the main purchase be posted at the firm or non-firm index price? Further, should the main purchase use the HLH price or the LLH price?

    Second, does IPC contribute to the D-J Mid-Columbia index? If so, is there any need to consider what should happen if IPC/IES is the main contributor to the Index on a given day? It is not known if this condition is a true concern without in-depth review of the volumes transacted. This was not possible in the time allowed.

We do note in the D-J information purchased for our use that there are days when the Index is calculated by a survey. On these days, D-J simply conducts a telephone survey to determine what a relevant “market price” is because the reporting parties do not contribute enough pricing and volume information to allow formulation of a reliable index number. If IPC/IES were able to influence the index number in a repeated fashion, this could theoretically allow the market price to be influenced by the firm to allow them to profit from the Statement framework.

Third, if firm transactions were undertaken, are customers paying twice for IPC capacity (once for units, once in purchases from outside)? Usually, but not always, firm transactions are more expensive than non-firm. It is not clear from the Statement whether the transactions are being marked from IES to IPC based on the D-J firm or non-firm index price under the Intramonth Power Marketing mechanism. It is also not clear from the Statement if they are *supposed* to be marked in this fashion. Due to time constraints, this could not be resolved during our review.

One of the issues with this third point may be “Are system resources being used to firm up resources that are purchased non-firm?” If they are, the question then becomes “At what D-J index price are these purchases transferred to IPC (firm or non-firm)? Since customers paid for resources, it would be important to ask if they should be charged for firm energy (since is their previously paid for assets that are making it firm)? This point could not be examined in the time allowed.

16. Are there any other potential problems associated with the Index price methodology?

We cannot be sure. However, we do have some questions about the use and selection of the Mid-Columbia Index.

To our knowledge, the Mid-C index is one of the more frequently reported and more liquid indices. In this respect, it is likely that the Mid-C index is a valid and high quality choice for the Statement’s settlement system.

However, from the documents presented, it is not clear where title to the power has transferred. This is another reason to have Commission access to comprehensive and complete transaction level detail for both IES and IPC. As a result, it is not possible to know if the Mid-C index is the most relevant index. For example, if sales were made by IES on behalf of IPC at COB, the difference between COB and Mid-C prices would accrue to the account of IES, while IPC would receive the price at Mid-C. These pricing differences are referred to as geographic basis.

Geographic basis occurs frequently and is a feature of many energy commodity markets. In the case of IPC, it is not clear whether the selection of Mid-C hurts or is beneficial to the firm. In the time allowed, we have not had the opportunity or the access to the data necessary to examine the historical pricing differential between the Idaho system receipt and delivery points and Mid-C.

An investigation of the delivery and receipt points available to IPC indicates that it is theoretically possible to sell into California across Sierra-Pacific's system as well as through COB. Further investigation would reveal more about the nature of the pricing relationships at these two points. It may be useful to determine if some California transactions are better settled using a different index value.

In addition, the summaries of the reviewed position reports indicate that several southwestern utilities and affiliated power marketers have been counter-parties of IPC/IES. It is not clear at what point the transaction title was transferred. Much of the generation from which these deals might be supplied is based in the Southwest for example, and the relevant point for many of their transactions would be Palo Verde (PV). The question in our mind is who is assuming the geographic basis risk in these cases? If IES accepts the geographic basis risk on behalf of IES/IPC, is it clear when the transaction is entered into whether it is for IES or IPC?

Under the Statement, IES appears to be able to designate the index to be used (Mid-C or PV). Say that IES assumes this risk. Under the Statement, can this geographic price risk be shifted from IES to IPC through subsequent transactions if subsequent events prove the price risk to be unfavorable? And alternatively, can the reverse occur? To us, the Statement as written does not preclude the possibility.

In brief, it seems likely, (but it is not clear without further assessment), that Mid-Columbia is the price that is usually appropriate. It may be appropriate for many deals but additional time, information, and analysis would be necessary to conclude this.

As a final observation, we do not know if the Commission under Final Orders intended to allow IES to profit from geographic basis. This may or may not have been considered desirable behavior. Based on our initial investigation, it appears that IES can profit from this type of trading involving IPC's assets.

Our concern is more focused on the possibility that the gains or losses could be allocated between the parties after the fact based on our understanding of the existing arrangement. Further discussions with Staff and IES/IPC would be necessary to resolve this.

17. Should sales and purchase prices be calculated separately or averaged together?

It may well be that there is no material difference between calculating sales and purchase prices bid/asked spread average of sales and purchase prices separately.

However, due to the fact that there is often a bid-asked spread (described previously), it would seem to make sense to calculate purchase and sale prices separately when cost-based transactions are involved. Note however, that the Index price reflects both purchases and sales together, so for Intramonth Power Marketing transactions, this may not be as important.

18. Is volumetric variance of energy supply or demand to be managed by IES on behalf of IPC?

    This is not specified in the Statement or in the Energy Trading and Financial Risk Management Policy as one of the risks to be managed. However, Commission Staff indicate that the forecasting functions for load and supply are supplied to IES to balance the system.

    As a result, we cannot be certain that this variance is to be managed by IES, but we believe that it is. The silence on this point in the Policy and the Stipulation may mean that IES intended (and the Commission intended for IES) to be able to profit from IES management of IPC's needs in this area.

    However, it should be pointed out that since IPC performs these activities with the incentive structure outlined in the Final Order, there is also the possibility that IES could exercise discretion over the forecast and effects of this variance to benefit their account by restating volumetric forecasts.

    In our view, the nature of this discretion is also a factor in determining whether IES and IPC operate under an "agency" or "arms length" relationship.

19. Do IES and IPC report risk using forward-looking measurements?

    According to the Energy Trading and Financial Risk Management Policy, IES appears to use only a cumulative stop-loss risk measurement to control and measure the risk associated with its trading activities.

    Based on our experience, we view this as a necessary and important tool. However, we find many firms have expanded beyond this type of control to include Absolute Risk Limits, Value at Risk (VaR), Daily Earnings at Risk (DeaR), and Credit Value at Risk (CVaR). We are unable to determine within the time allowed for this project if these measures are utilized by IES and IPC.

    We do feel that it is possible that a cumulative stop loss as opposed to an absolute stop loss limit for forward transactions may not adequately represent the risks being undertaken for IPC and its customers.

Generally, cumulative stop loss limits include any booked profit or loss since the start of the last measurement period.

One reason to have a forward looking risk measurement system would be to better understand the tradeoffs that the RMC and the traders were making with regard to the needs of IPC and the captive consumers. Without this type of system, an external review of the trade-offs being made between risk and return cannot be analyzed.

If measures like VaR, DeaR, and CVaR are calculated and utilized by IES or IPC, it would be useful, appropriate, and essential for these measures to be utilized in reviewing the nature of the relationship between IPC and IES. In addition, these measures could help determine the prudence and reasonableness of particular transactions since portfolio managers and traders often use them prospectively to determine if a transaction should be entered into. While matching physical positions is important, use of VaR and CVaR is a direct way to determine if a transaction was considered "risk reducing" or a hedge at the time it was entered.

20. What happens in the event that IPC wishes to replace IES as its marketing, trading, and risk management service provider?

This is not clear from the documents received and reviewed. In some service agreements, these terms are clearly defined. For example, IES might have the obligation to transfer trades, information, and systems back to IPC at no additional cost if the services contract expires, is voided, or terminated. This provision is designed to prevent the possibility for IES to arbitrarily determine how much compensation it is due as a "wind-down" fee at a time when serious and quick action might need to be taken to manage the portfolio or assets with revised objectives or strategies.

In no way are we suggesting that IPC consider such a replacement option at the current time. Rather, the precise parameters around an exit strategy would need to be developed and implemented between the parties; however, we suggest that thought be given to this well in advance of any possible need to implement it.

The reason to consider these obligations in the current environment is to shed further light on the nature of the relationship between IES and IPC. Again, if IES can exercise discretion over these events, it may imply that IES is acting as agent for IPC. It also may imply that IES has a conflict in its role as a spec trader who can cross transactions with IPC and its role as a portfolio manager for IPC's captive consumers.

III. A. Provide Observations About How The Proposed Services Agreement Between Idaho Power Company (IPC) and Idacorp Energy Services (IES) Might Be Modified To Provide Additional Protections To Customers of Idaho Power Company (IPC) Served Under Regulated Tariffs.

In our view, the consideration of modifications to the existing framework stem partly from the Commission's view as to the type of philosophy they envisioned and feel they implemented for the PCA clause. If they were intent on maintaining the "lower of cost or market" philosophy for prudently incurred and reasonable expenses, then observations about modifications may be relevant.

It should be pointed out that we have focused on expenses in discussing the "lower of cost or market" criteria. It would also be useful to focus on the philosophy towards revenues and what the captive consumer might expect. We would suggest the analog might be the "higher of revenue received or market".

Given that disagreements may exist regarding the philosophy, prudence, and reasonableness, what observations are relevant?

One of the most important concerns throughout this report revolves around the decision-making process that IPC and IES employ. We do not totally understand or appreciate the facts surrounding the nature of this relationship after only eleven days of analysis.

If the nature of the relationship is determined to be an "arms length" one, it will be important for IPC to ensure that it is making prudent decisions for supply. This is a logical and necessary step that might be a component of a prudent business process that would lead to reasonable business expenditures and receipts for captive consumers.

We do feel that it is important to separate fully the needs of captive consumers and the interests of shareholders. One method to achieve this would be for IPC to have a knowledgeable supply officer totally independent from IES who can make decisions for system supplies and sales. This would be especially important for determining prudence and reasonableness if IES maintains a spec book and can cross trades between its spec book and the IPC system book.

From a business perspective, based on our knowledge of trading and risk management, we believe that there is at least a valid question as to whether the status of IES's FERC filing as an Affiliated Power Marketer and the lack of a signed agreement for services between IES and IPC affect its ability to recover the fixed and incentive fee.

In addition, if the Statement had resulted in a signed contract, there would seem to be some doubt that IES would be in compliance with Section 2.C.8 of the Statement which reads that "IES shall observe all applicable laws, ordinances, rules, and regulations relating to delivery of the Services, and shall procure and maintain in force, at its sole expense, all registrations, permits, licenses, and approvals required by law or governmental authority to perform the Services." This has been presented as the contemplated document that would govern the activities between the parties.

Further, based on our trading and risk management experience, from a business perspective, we do believe that if written trading authority does not exist between IPC and IES, sophisticated counter-parties would not trade directly with IES. Another consideration will likely be the existence of credit support from IPC to IES. If both of these characteristics are absent, it is our expectation that sophisticated counter-parties would only trade with IPC.

In a separate matter, it is important to examine if it is possible that the incentive mechanism utilized for Intramonth Power Marketing creates an incentive for IES to refrain from entering into term transactions to protect the ratepayer of IPC from market price volatility.

Based on the information reviewed to date, we see no direct evidence that IES has purposely engaged in day-ahead transactions with the intent to profit instead of managing price volatility for IPC and its consumers.

However, in our view, because there is an incentive paid between cost and market price for only one category of transactions (Intramonth Power Marketing), we believe it is possible that the existing structure could create an incentive for IES to transact more often on behalf of IPC in this category. At least, it may *appear* to an outsider that this could occur. This propensity might be very difficult for an outsider to trace.

For example, a change in strategy of buying forward for hedging against unwanted price volatility to reliance on the day-ahead spot market might be caused simply by a change in market view.

Or, it is possible that the traders might wish such a change in strategy to attempt to profit from it, and leave the risk if they are wrong to IPC.

III. B. Provide Recommendations and Suggestions About How The Proposed Services Agreement Between Idaho Power Company (IPC) and Idacorp Energy Services (IES) Might Be Modified To Provide Additional Protections To Customers of Idaho Power Company (IPC) Served Under Regulated Tariffs.

Based on the objectives and concerns identified previously, we present the following suggestions and recommendations based on our understanding of the existing rules in place between IPC and IES, the services agreement that we are informed is pending, and the possible goals of the PCA regulatory process.

First, we suggest that Commission Staff have full audit authority for all IES and IPC information from high-level strategy and objectives down to the comprehensive and complete transaction level. Further, we suggest that it would be useful to have electronic, password protected, limited historical access to the IES and IPC position tracking system for the period under review. This could replace the current system of note-taking which unnecessarily handicaps Staff's abilities, especially during short time-frame reviews. In-camera proceedings may also need to be revisited, and reoriented in this case to limited and controlled electronic access.

Second, we suggest that Commission Staff have full audit and review authority for all risk measurement models, pricing models, option models, index calculations, forecasting tools, forecasting output, forecasting input assumptions, related memos, correspondence internally and with external parties involved in trading and risk management, and asset valuation models utilized by IES and IPC.

Third, we suggest that Commission Staff have access to audit marks made by internal and external auditors of IES and IPC.

Fourth, we suggest that the Commission Staff have access to all records regarding the hedging objectives, strategies, and tactics engaged in by the regulated company and its agent (IES and IPC).

Fifth, we suggest that the framework address additional detailed points of responsibilities and procedures on which it is currently silent. For example, who currently manages emission-trading credits and for whose account do these accrue?

We understand and appreciate the sensitivity that IES and IPC would have to all of these points. It is quite possible that leakage of this information to trading counter-parties could result in substantial commercial damage to IES, and this is not a fear to be taken lightly by the commission.

In addition, we are very sensitive to the criticism that the Commission has the possibility for engaging in hindsight review with selective disallowances if such changes were to be implemented. With access to such data, the Commission and its staff must remain vigilant in their efforts to utilize this expanded knowledge in a fair, even-handed, and informed manner.

On the other hand, we also considered a more intrusive variety of alternatives to mitigate the potential weaknesses of the current system that we perceive. One of these was to consider whether IPC and/or IES should be required to enter into a pre-approval process with the Commission on a strategy-by-strategy basis.

To give the Commission the right to explore strategies and rule on them before the fact seems unworkable to us in markets that trade continuously every business day. In addition, this is not the regulatory direction in several other major and important proceedings. Even if this were done at the broad macro level ("setting strategic direction") akin to a CCN process, it is our belief that the complexity of the decision-making means that this type of guidance is better and more comprehensively managed by the companies themselves. Therefore, we would *not* suggest a Commission pre-approval process.

Having made these observations, we wish to add that we do not believe that the captive consumer should remain silent on his wishes for managing risk and return from assets he helped pay to construct. We are aware of substantial theoretical and practical research on the risk preferences of consumer groups that is being undertaken in other jurisdictions. This type of approach holds promise for providing feedback directly to the portfolio manager to communicate the wishes of the captive consumers with regard to risk and return. However, this research is not yet fully complete; and as such, it remains an interesting, yet immature solution.

We do believe that the captive consumer for the regulated IPC has a right to expect expert and forthright management of his assets. In addition, he is paying the bill for the decisions undertaken by the portfolio manager; consequently, he should be able to ensure that he is receiving fair and unbiased management of his interests. He should also expect "sunshine" on the process used to manage his interests under the PCA.

We believe that it is possible that greater and more in-depth examination of past transactions will be objectionable to IES and IPC. However, we do not see a viable alternative based on the current program structure. One alternative may be to modify the program design parameters to limit the audit needs and rights. These alternatives are explored in the next section.

III. C. Provide insight and observations about how the existing Idaho PCA framework might be modified.

In our view, modifications to the existing framework stem partly from the Commission's view as to the type of philosophy they envisioned and feel they implemented for the PCA clause.

If the philosophy is based on prudent, reasonable expenses based on the philosophy of "lower of cost or market", the following basic elements are relevant in considering possible changes to the PCA clause.

1. If the customers are absorbing some of the risk or, alternatively, the customer assets are used to reduce the portfolio manager's trading risk, then it would seem that the captive consumer should receive some sort of compensation. One alternative might be a transaction or usage fee to the customers – for example, a credit use fee with no residual risk to the customers from the downside.

2. An initial justification for the spec book was to retain "intellectual capital" available to the organization; therefore, the customers should see some utilization of this intellectual capital for their account.

In the first case, the structure should look more like a debt instrument e.g., perhaps 1-2% return on the capital of the regulated company book employed to enable the creditability of the spec book under a "comfort letter" arrangement.

In the second case, if a spec book is to continue to be allowed, the idea would be that the intellectual capital should ensure that the market price view should be reflected in the overall position of each book. While the regulated book should have a significantly lower risk tolerance and therefore much lower open position size and cost volatility, it is still reasonable to expect that the regulated book should be most heavily hedged at the time and for the periods the spec book has its greatest speculative length. Similarly, as the spec book shifts to a short position, it is reasonable to assume that the regulated book hedges would lighten up at the same time. So, the data should be accessible and verifiable that the directional tendencies of the speculative position should be reflected in the regulated book directional tendencies **simultaneously.**

We are particularly troubled by the notion that the captive consumer may receive fewer of the benefits from the regulated company assets.

While we too want to increase efficiency of asset management by increasing the sophistication of the portfolio manager, we also feel that the implemented system should not give full discretion for rule-making and the governing framework development and administration to the portfolio manager. Under the existing structure, we cannot readily determine if the features of the assets that the consumer paid for are being compensated for by the portfolio manager.

Finally, we do not believe that a complete enough discussion has been held to identify whether consumers should be interested in profit maximization, cost minimization, bill volatility minimization, or some combination of these objectives.

Under the current system, we see the potential for conflict in the interests of the captive consumer and the portfolio manager in the following areas.

- It is not explicit that the captive consumer is being compensated for risks that he is being subjected to;
- The portfolio manager can enter into transactions for his own spec book or on behalf of the captive consumer with great discretion;
- The portfolio manager is subject to limited review, and limited data are available to outsiders;
- The design of the system does not appear to provide parallel rewards for different types of transactions;
- The goals and objectives of the captive consumer are not well defined;
- Market prices do not readily exist for all categories of transactions to be undertaken;
- Risk measurement may not be undertaken on a forward-looking basis; and
- Allocation of transactions capitalizing on geographic and quality basis and certain products such as emission credits are not clear.

In general, we note that there is an appearance that IES has too much discretion in setting the guidelines and rules for the transaction. Any change should also address this concern.

If these concerns are valid, do potential solutions exist that might better align the interests of the parties, the compensation paid, and the incentive fee structure? The answer depends on the goals and objectives of the captive consumers, the Commission, and the regulated company.

In our view, it is desirable that any implemented program avoids even the appearance of a conflict of interest between the interests of the captive consumers and the portfolio manager.

These observations, admittedly incomplete, lead us towards the belief that the nature of the relationship between IES and IPC tends towards an "agency" relationship.

If an "agency" relationship were in place, we believe that it would be important for IES to be able to serve the needs and interests of IPC first. If these needs and interests include a focus on the philosophy of prudent and reasonably incurred "lower of cost or market" expenses, then we feel it would be important to resolve the issues of speculation for other accounts, issues surrounding crossing of trades between books, issues surrounding review of previously entered transactions, issues involving real-time oversight of transactions, issues involving how captive consumer interests are advocated, and develop what a prudent implementation of these might look like.

If an "arms-length" relationship were in place, we believe that it would be important for IPC to be able to serve its needs through an effective and knowledgeable individual or team to be advocating captive customer interests in the marketplace directly.

There are three potential solutions that we can envision based on the limited time that we have had to consider the situation.

1. First, IES would act as agent for the regulated IPC.

   Under this alternative, IES would not be allowed to manage a spec book for its own account.

   Review oversight and access to transaction level data would be least intrusive, minimizing the potential for hindsight review. IES would receive a fixed fee intended primarily to cover its costs plus reasonable profit of operating a trading operation. In addition, objectives would be established by IPC for IES performance. These objectives might include a cost reduction or volatility reduction as an objective. This might be specified as a reduction in purchased power cost by 10% over the average of the past five years, an increase in contribution from off system sales and purchases by 15%, or a reduction in wholesale power market price volatility by 10% over the average of the past five years. If these objectives were achieved by IES, the firm might be eligible for an incentive fee up to 50% of the savings or 15% of total power purchases and sales revenue or 2-4% of the regulated book's capital employed, whichever was lower. The Commission would establish clear guidance for PCA program goals and objectives.

   The tabulated percentages are illustrative only for discussion, and do not constitute recommendations on the part of the consultant.

2. Under the second alternative, IES could act as agent for the regulated IPC.

   Under this alternative, IES would be allowed to manage a spec book for its own account; however, no transactions would be allowed between the IPC spec book and the IPC regulated book.

   Review oversight and access to transaction level data would be moderately intrusive, increasing the potential for hindsight review. One major focus of the review would be to determine if the portfolio manager were engaging in activity to circumvent the "no crossed trades" rule. This might be focused on activities such as third-party "sleeving". IES would receive a fixed fee intended primarily to cover its costs plus reasonable profit of operating a trading operation. In addition, objectives would be established by IPC for IES performance. These objectives might include a cost reduction or volatility reduction as an objective.

This might be specified as a reduction in purchased power cost by 10% over the average of the past five years, an increase in contribution from off system sales and purchases by 15%, or a reduction in wholesale power market price volatility by 10% over the average of the past five years. If these objectives were achieved by IES, the firm might be eligible for an incentive fee up to 30% of the savings or 10% of total power purchases and sales revenue or 1-3% of the regulated book's capital employed, whichever was lower. The Commission would establish clear guidance for PCA program goals and objectives.

The tabulated percentages are illustrative only for discussion, and do not constitute recommendations on the part of the consultant.

3. Third, IES could act as agent for the regulated IPC.

   Under this alternative, IES would be allowed to manage a spec book for its own account; and, transactions would be allowed between the IPC spec book and the IPC regulated book with specific and detailed rules. IPC would appoint an independently compensated and incentivized system supply manager who would be allowed to sit on IES's trading floor.

   Review oversight and access to transaction level data would be most intrusive, examining the directional tendency of both books, and increasing the potential for hindsight review. IES would receive a fixed fee intended primarily to cover its costs plus reasonable profit of operating a trading operation. In addition, objectives would be established by IPC for IES performance. These objectives might include a cost reduction or volatility reduction as an objective. This might be specified as a reduction in purchased power cost by 10% over the average of the past five years, an increase in contribution from off system sales and purchases by 15%, or a reduction in wholesale power market price volatility by 10% over the average of the past five years. If these objectives were achieved by IES, the firm might be eligible for an incentive fee up to 5% of total power purchases and sales revenue or 1-2% of the regulated book's capital employed, whichever was lower. The Commission would establish clear guidance for PCA program goals and objectives.

   The tabulated percentages are illustrative only for discussion, and do not constitute recommendations on the part of the consultant.

It is important to note that in all cases, we are suggesting that the current incentive structure for intramonth power marketing be modified to ensure better alignment between the objectives of the captive consumers and the needs of the company's shareholders to be compensated for the activities their capital is sponsoring. Even with the philosophy of "lower of cost or market" for prudently incurred, reasonable expenses, captive consumers should be happy to encourage and pay for delivered performance. Wherever possible, they should be encouraged to speak for themselves. When they cannot, our view is that the Commission must speak for them.

From the perspective of IES and IPC, we are reasonably certain that there would be discomfort with or a challenge to the rationale of limiting transactions that are "crossed" between the companies regulated and spec books, or even limits to IES on its ability to run a spec book. In our view, modification of these parameters is not necessarily uncommon as a step to prevent conflicts of interest.

We believe that IES and IPC should appreciate the rationale in this matter. They need only refer to their own Energy Trading and Financial Risk Management Policy. In this document, they have placed the following requirement:

"Restrictions on Private and Personal Trading Activity – All personnel involved in or with knowledge of the Company's trading activity, with respect to the commodities and financial instruments covered by this guide, are prohibited from trading such commodities and their derivative financial instruments for any accounts other than those of Idaho Power Company."

The usual rationale for such restrictions is to prevent conflicts of interest between the trader and the company that employs him. If a trader can trade two books, for his company and himself, engaging in a trade prior to his company engaging in it, or in such a way that his company may be disadvantaged are situations that most companies would wish to prevent. Some companies even go so far as to terminate the employment of someone who violates the terms their trading and risk management policy.

It is our opinion that IES and IPC should expect nothing less from the relationship between the organizations themselves than they do from the traders they employ.

Conclusions And Recommendations

At the outset, we established three objectives for the study:

I. Examine the past and existing Idaho PCA frameworks to see where we have been.
II. Provide Observations About the Current Status of Activities of Idacorp Energy Services (IES) on Behalf of Idaho Power Company (IPC) To Give Insight As To How the Goals and Expectations For the Idaho PCA Framework Have Been Met.
III. Provide observations, recommendations, and suggestions about how the proposed services agreement between Idaho Power Company (IPC) and Idacorp Energy Services (IES) might be modified to provide additional protections to customers of Idaho Power Company (IPC) served under regulated tariffs; and provide insight and observations about how the existing Idaho PCA framework might be modified.

We have made specific observations and suggestions regarding where the Commission might start in reviewing the relationship between IES and IPC and their interaction with a PCA clause.

We have also offered insight as to what has happened or what could possibly occur between the IES and IPC given our understanding of their current relationship.

Based on our understanding of the current relationship between IES and IPC, we feel there is the potential for concern regarding the relationship between the parties. As a minimum, there are many items that are not clear. This lack of transparency is most easily and directly addressed through expanded analysis of additional information that is not available to Commission Staff currently. From our brief review, we find these areas of concern are definable and understandable. To balance between the needs of the captive consumer and the companies, we believe the Commission has a direct role to play in addressing these concerns.

Based on our understandings and assumptions, we suggested three alternative structures for the Commission and staff to consider when moving forward with energy trading and risk management activities in Idaho. A fixed fee and incentive program is contained in all three alternatives.

We would suggest that the Commission carefully consider the unique and difficult times the WSCC participant finds himself in. Credit defaults, energy and capacity shortages, counter-party non-performance, bankruptcies, low water inventories, environmental demands, rationing, and other factors create an extremely difficult environment for any company to operate in. Uncertainty in regulatory guidelines only compounds what is already a very difficult set of operating conditions. In the current operating environment, any changes need to be carefully considered and even-handedly applied to prevent additional difficulties.

We feel that energy trading and risk management is an important component of the new contestable wholesale market environment. In our view, these new tools and business processes can help address these uncertainties in a much more flexible and useful way than before. Companies should be encouraged and incentivized to engage in these activities in well-designed programs. Commissions would be well advised to carefully balance company and captive consumer needs from both a transition step and final state perspective. Appropriately designed incentive ratemaking with careful, comprehensive, and considered reviews is an important tool for companies trying to make that transition.